Decision 05-01-031 January 13, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of its 2004 Energy Resource Recovery Account (ERRA) Forecast Revenue Requirement, for Review of Contract Administration, Least Cost Dispatch and Procurement Activities during the Record Period January 1, 2003, Through May 31, 2003, and for Approval of its 2004 Ongoing Competition Transition Charges (CTC) Revenue Requirement and Proposed Rate Design. (U 39 E)	Application 03-08-004 (Filed August 1, 2003)

Ann H. Kim and Robert B. McLennan, Attorneys at Law, for Pacific Gas and Electric Company, applicant.

Downey, Brand, LLP, by Dan L. Carroll, Attorney at Law, for Merced Irrigation District; Joy Warren, Attorney at Law, for Modesto Irrigation District; Alcantar & Kahl, LLP, by Michael Alcantar, Attorney at Law, for Cogeneration Association of California; Barkovich & Yap, by Barbara Barkovich, Attorney at Law, for California Large Energy Consumers Association; James Ross, for Midway Sunset Cogeneration Company; Don Schoenbeck, for Mid-Set Cogeneration Company; Alcantar & Kahl, LLP, Nora Sheriff, Attorney at Law, for Energy Producers & Users Coalition; and Alcantar & Kahl, LLP, by Karen Terranova, for Sargent Canyon Cogeneration Company, interested parties.

Christopher J. Mayer, for Modesto Irrigation District, protestant.

Regina Deangelis, Attorney at Law and Laura L. Krannawitter, for the Office of Ratepayer Advocates.

Paul Douglas and Kayode Kajopaiye, for the Energy Division.

TABLE OF CONTENTS

OPINION REGARDING THE 2004 ONGOING COMPETITION TRANSITION CHARGE

I. Summary

On August 1, 2003, Pacific Gas and Electric Company (PG&E) filed its application for the adoption of its 2004 Energy Resource Recovery Account (ERRA) revenue requirement forecast, for review of its contract administration, least cost dispatch and procurement activities for the record period January 1, 2003 through May 31, 2003, and for approval of its proposed 2004 rates for the ongoing Competition Transition Charge (CTC).

In Decision (D.) 04-06-012, we issued an interim opinion on PG&E's 2004 ERRA revenue requirement and the 2004 ongoing CTC revenue requirement. We stated in that decision that the interim ongoing CTC revenue requirement amount "shall be subject to change or adjustment as may be determined in the decision addressing the CTC revenue requirement issue which has been the subject of evidentiary hearings." (D.04-06-012, p. 21.) We held evidentiary hearings on the ongoing CTC issue in April 2004.

Today's decision concludes that the adjustments to the CTC calculation, as recommended by two of the parties, are not warranted. The 2004 ERRA revenue requirement of $2.189 billion, and the 2004 CTC revenue requirement of $144.026 million, both of which were adopted on an interim basis in D.04-06-012, are adopted without change.

II. Background

In D.02-10-062, the Commission established the ERRA balancing account to recover PG&E's procurement plan power costs.[1] The ERRA records the authorized ERRA revenue requirement and actual power costs to determine the recovery of PG&E's procurement plan power costs, excluding the costs associated with the California Department of Water Resources (DWR) power contracts.

In D.03-10-059, the decision addressing PG&E's 2003 ERRA proceeding, we approved a stipulation between PG&E and the Office of Ratepayer Advocates (ORA) that allowed PG&E to include its 2004 ERRA forecast and ERRA reasonableness showing for the first five months of 2003[2] in its August 1, 2003 ERRA balancing account review filing.[3] PG&E filed the above-captioned application on August 1, 2003.

Pursuant to D.03-07-030, PG&E's application also included its calculation of the 2004 ongoing CTC.[4]

---

[1] D.02-10-062 was modified in part by D.02-12-074.

[2] A decision regarding PG&E's contract administration, generation resource dispatch, and procurement activities for January 1, 2003 through May 31, 2003 will be issued separately. This proceeding is also addressing PG&E's contract administration and procurement activities for the period from June 1, 2003 through December 31, 2003.

[3] We noted in D.03-10-059 that the stipulation regarding the timing of filing the ERRA application was in conflict with the procedural schedule for filing the ERRA application that was adopted in D.02-12-074. The procedural schedule in D.02-12-074 was revised in D.04-01-050 to allow for PG&E's filing of its 2004 ERRA forecast and 2003 reasonableness review in August 2003. (D.04-01-050, pp. 175-177.)

[4] The ongoing CTC, which is often referred to as "tail CTC," refers to the CTC charges that continue beyond the end of the transition period until the costs identified in Pub.

Footnote continued on next page

Following the prehearing conference, the February 3, 2004 scoping memo and ruling (scoping memo) determined that there was no need for an evidentiary hearing on the 2004 ERRA revenue requirement. Due to the protest of the Modesto Irrigation District (Modesto ID) to PG&E's application, an evidentiary hearing on the CTC issue was scheduled for April 2004. The scoping memo also granted PG&E's request for an interim decision on the 2004 ERRA revenue requirement and the 2004 ongoing CTC revenue requirement. Since the scoping memo called for the issuance of an interim decision before the CTC issue was to be litigated, the scoping memo stated that the interim decision could be changed or adjusted by a subsequent decision addressing the CTC issue, and that the granting of the motion for an interim decision shall not prejudge the evidentiary hearing regarding the CTC issue.

On June 9, 2004, in D.04-06-012, we adopted on an interim basis a 2004 ERRA revenue requirement of $2.189 billion, and a 2004 ongoing CTC revenue requirement of $144.026 million.

Evidentiary hearings on the CTC revenue requirement issue were held on April 5 and April 7, 2004. During the April 7, 2004 hearing, PG&E's witness John Pappas testified that he might have to correct his testimony to reflect that some qualifying facility (QF) contracts may need to be removed from the ongoing CTC revenue requirement calculation. At the hearing, the assigned Administrative Law Judge (ALJ) established a schedule for possible corrections to Pappas' testimony and for parties to determine if additional hearings on the corrections would be needed. PG&E submitted its corrections on April 23, 2004 in a

---

Util. Code § 367 are fully recovered. (All code sections cited in this decision refer to the Public Utilities Code.)

document entitled "Errata … To Prepared Testimony on Forecast Issues" (Errata), which was admitted into evidence as Exhibit 18.

At the May 3, 2004 prehearing conference, Modesto ID and the Merced Irrigation District (Merced ID)[5] requested that that they be given additional time to determine if hearings on the Errata would be needed, or if additional exhibits containing data responses from PG&E about the Errata should be included. On May 18, 2004, PG&E, with the agreement of the Irrigation Districts, submitted a letter to the ALJ requesting that the Errata and seven PG&E data responses related to the Errata be admitted into evidence, and that an agreed-upon briefing schedule on the CTC issues be adopted. In a May 25, 2004 ALJ ruling, the Errata and the data responses were admitted into evidence and the recommended briefing schedule was adopted.

In a June 4, 2004 ruling, the ALJ solicited comment on whether the Errata could affect the prior calculations of the ERRA and CTC revenue requirements. The parties were directed to comment on the Errata's effect in their opening and reply briefs.

Opening and reply briefs were filed by PG&E, Merced ID and Modesto ID. The CTC issue was submitted on June 25, 2004.

III. Positions of the Parties

A. PG&E

The Irrigation Districts take issue with PG&E's calculation of the 2004 ongoing CTC for municipal departing load customers. PG&E contends that it is

---

5 The Modesto ID and the Merced ID are collectively referred to as the "Irrigation Districts."

merely implementing the methodologies set forth in decisions emanating from Order Instituting Rulemaking (R.) 02-01-011, the direct access suspension rulemaking. PG&E asserts that contrary to the Irrigation Districts' claim, the Commission has adopted a calculation methodology for municipal departing load customers, as well as methodologies for calculating the ongoing CTC for direct access and customer generation departing load customers.

PG&E states that in D.02-11-022, the Commission adopted a "total portfolio" methodology for calculating the ongoing CTC for bundled and direct access customers.[6] In D.03-04-030, the Commission adopted a "statutory" methodology for calculating the ongoing CTC for customer generation departing load customers.[7]

In the municipal departing load phase of R.02-01-011, PG&E states that the Commission addressed the methodology for calculating the ongoing CTC for municipal departing load. According to PG&E, the Irrigation Districts, as well as the California Municipal Utilities Association (CMUA), were active in this phase. PG&E contends that the Merced ID and CMUA argued that the statutory methodology should be used to calculate the ongoing CTC for municipal departing load, and that it would be unlawfully discriminatory to treat municipal departing load differently from customer generation departing load.

PG&E asserts that in D.03-07-028, the Commission adopted the statutory methodology for calculating the ongoing CTC for municipal departing

---

[6] PG&E states that the total portfolio methodology includes the utility's retained generation portfolio costs, and the costs specifically identified in § 367(a).

[7] PG&E states that the statutory methodology includes only the costs specifically identified in § 367(a), and does not include utility retained generation costs.

load. According to PG&E, this ongoing CTC calculation includes the above-market § 367(a) power purchase contract obligations netted against all applicable below-market contracts. PG&E quotes from Finding of Fact 25 and Ordering Paragraph (OP) 3 of D.03-07-028 in support of its argument that the Commission has adopted a methodology for calculating the ongoing CTC for municipal departing load customers. PG&E contends that the Irrigation Districts' claim that the Commission has not yet adopted a calculation methodology for ongoing CTC for municipal departing load is simply wrong.

PG&E further asserts that although rehearing of D.03-07-028 was sought by CMUA, Merced ID and Modesto ID, none of these parties raised any issue about the Commission's adoption of the statutory methodology for calculating the ongoing CTC for municipal departing load customers. The Irrigation Districts now appear to support the use of a total portfolio methodology for calculating the ongoing CTC for municipal departing load customers because the use of the statutory methodology results in a higher ongoing CTC rate for municipal departing load customers relative to direct access and bundled customers. PG&E contends that the Commission should reject the Irrigation Districts' efforts to relitigate the issues that were resolved in D.03-07-028, and which were not raised on appeal.

Since is it acting consistently with the Commission's prior decisions, PG&E recommends that its proposed 2004 ongoing CTC revenue requirement and rates be approved.

Modesto ID also challenges PG&E's use of 5.18 cents per kilowatt hour (kWh) as the benchmark for calculating the ongoing CTC. PG&E asserts that the use of this benchmark is consistent with D.02-11-022. In that decision, PG&E was directed to use the California Energy Commission's (CEC) previous estimate

(4.3 cents) of the cost of a gas-fired combined cycle unit to calculate the 2003 direct access cost recovery surcharge. In D.03-07-030, the Commission stated that the 4.3 cents benchmark would be subject to revision in the future to reflect updated data. In response to Modesto ID's protest to the application that the 4.3 cents benchmark was outdated, PG&E used the CEC's updated benchmark of 5.18 cents per kWh as the benchmark for PG&E's 2004 ongoing CTC calculation.

PG&E asserts that the 5.18 cents benchmark is consistent with the benchmark that was agreed to and adopted in Southern California Edison Company's (SCE) 2004 ERRA in D.04-04-066. Given the language in D.02-11-022, D.03-07-030 and D.04-04-066, PG&E contends that it is both lawful and reasonable for the Commission to adopt the 5.18 cents benchmark in PG&E's 2004 ERRA proceeding.

PG&E believes that the Irrigation Districts' proposed use of a 6.87 cents per kWh benchmark should be rejected for a number of reasons. The first reason for rejecting this proposed benchmark is because D.03-07-030 stated that the market benchmark adopted in D.02-11-022 should be revised to reflect more updated data for use in future ongoing CTC calculations. PG&E asserts it is unreasonable to interpret this "more updated data" to mean that a completely different set of assumptions and inputs should be used.

PG&E's second reason for rejecting the Irrigation Districts' proposed benchmark is that it does not make sense to establish utility-specific market benchmarks for each utility's respective ERRA proceeding. Instead, the market benchmark for calculating ongoing CTCs should be decided in a generic proceeding involving all the investor-owned utilities (IOUs) and parties interested in ongoing CTC calculation issues.

The third reason is given the language in D.03-07-030, as well as the interest in having a consistent statewide market benchmark, it is reasonable to use the 5.18 cents benchmark since it is the same benchmark adopted in D.04-04-066 for SCE's ERRA.

The fourth reason for rejecting Modesto ID's adjustments to the benchmark are because the adjustments are unreasonable. For example, PG&E asserts that for the low fuel cost scenario, Modesto ID replaces a 20-year levelized stream of forecasted gas prices with a one year forecast, which is subject to short term market volatility. In the high fuel cost scenario, Modesto ID assumes unreasonably high fuel prices.

The fifth reason for rejecting the Irrigation Districts' benchmark is that it makes no sense to apply one benchmark to municipal departing load customers while applying the CEC based benchmark for all other categories of customers, as Modesto ID proposes to do in this proceeding.

The Irrigation Districts also propose to disallow 16 of the QF contracts shown in Exhibit 20 from the calculation of the 2004 ongoing CTC revenue requirement. They assert that the QF contracts should be disallowed because they were extended beyond their original expiration dates.

PG&E takes the position that the 2004 ongoing CTC revenue requirement should not be reduced by disallowing these QF contracts because the prohibition in § 367(a)(2) against QF contract extensions applies only to buy-outs, buy-downs, and renegotiations. PG&E contends that in D.02-08-071 and D.03-12-062, the Commission required the IOUs to extend their existing and recently expired QF contracts through the end of 2004, and that the IOUs did not buy-down, buy-out, or renegotiate these contracts. PG&E asserts that there is nothing in § 367(a)(2) that bars the Commission from granting ongoing CTC treatment to a QF contract that the Commission requires the utility to extend. PG&E also asserts that it would be unreasonable for the Commission to order the IOUs to extend their QF contracts on the one hand, yet deny ongoing CTC cost recovery on the other.

Modesto ID seeks to reduce its ongoing CTC obligation even further by arguing that § 367 precludes the recovery of costs associated with certain renegotiated contracts where the new contract price is higher than the contract price that was collected in Commission approved rates on December 20, 1995. Specifically, Modesto ID seeks to disallow 200 of the QF contracts that were offered short-run avoided cost (SRAC) amendments.

PG&E argues that the SRAC amendments are eligible for ongoing CTC cost recovery pursuant to the statutory language in § 367(a)(2) which states in part: "Costs associated with any … renegotiation of the contracts shall continue to be collected for the duration of any agreement governing the … renegotiated contract." (PG&E, Reply Brief, p. 2; Pub. Util. Code § 367(a)(2).) PG&E also points out that the IOUs were directed by the Commission in OPs 2 and 5 of D.01-06-015 to enter into the SRAC amendments.

PG&E responded to the June 4, 2004 ruling about the effect of Exhibit 18 on previous ERRA and CTC calculations. PG&E asserts that for 2003, the inclusion of the cost of the five QF contracts would have increased the 2003 ERRA and reduced the 2003 ongoing CTC revenue requirement. However, in 2003, bundled customers' rates were still frozen, and the cost responsibility surcharge for direct access and municipal departing load customers was capped at 2.7 cents per kWh. Thus, none of these customers' rates would have been affected by the five QF contracts since the Commission had not yet established an ongoing CTC revenue requirement for 2003 for these customers. PG&E contends that any calculation of the 2003 ongoing CTC should occur in R.02-01-011.

For years prior to 2003, PG&E states that the removal or inclusion of the five QF contracts referenced in Exhibit 18 cannot affect PG&E's "regular" CTC because those transition costs have been resolved in PG&E's Annual Transition Cost Proceedings and in D.03-12-035, the decision adopting PG&E's Modified Bankruptcy Settlement. Rates to implement the Modified Bankruptcy Settlement were approved in D.04-02-062.

B. Irrigation Districts

Modesto ID and Merced ID contend that PG&E's proposed calculation of the 2004 ongoing CTC rate for municipal departing load customers is four to six times higher than the CTC rate PG&E proposes to charge its own bundled customers. According to Modesto ID, this results in a discriminatory and anti-competitive effect on municipal departing load customers. Modesto ID asserts that PG&E has provided no evidence to indicate that departing load customers created a greater share of PG&E's generation costs or received any greater benefits than bundled or direct access customers. Based on the evidence presented in this proceeding, Modesto ID contends that the 2004 ongoing CTC revenue requirement charged to municipal departing load customers should be no greater than $0.00167 per kWh.

The Irrigation Districts take the position that the Commission has "expressly reserved and has never yet decided the issue of how to calculate" the ongoing CTC for municipal departing load customers. (Merced ID, Reply Brief, p. 4.) The Irrigation Districts contend that the CTC revenue requirement calculation and rate design for municipal departing load customers should be consistent with the method that is used for bundled and direct access customers.

The total portfolio method that is used for bundled and direct access customer factors in PG&E's retained generation. Utility retained generation (URG) is one of the lowest cost resources in PG&E's portfolio, and makes up a significant volume of PG&E's lower cost resources. When PG&E's URG is included in the calculation, the rates for bundled and direct access customers are considerably less than the rates for municipal departing load customers.

Modesto ID states that it is only seeking to ensure that the CTC for municipal departing load is calculated in accordance with applicable statutory provisions, and that its position is consistent with its participation during the municipal departing load phase of R.02-01-011. Modesto ID contends that D.03-07-028 provides that the cost recovery surcharges for municipal departing load customers include CTC "covering the components specified in Section 367." (D.03-07-028, OP 3.c.) Merced ID contends that OP 3(c) of D.03-07-028 refers to § 367 in its entirety, and not just to § 367(a). Modesto ID asserts that PG&E erroneously interprets this requirement by using the requirement in D.03-04-030 that customer generation departing load customers pay ongoing CTC, the eligible costs for which "will be limited to those cost categories defined in Public Utilities Code Sections 367(a)(1)-(6)" and "based on the market benchmark adopted in D.02-11-22 [sic] regarding DA CRS [direct access cost recovery surcharge]." (Modesto ID, Reply Brief, pp. 2-3; D.03-04-030, p. 33.)

Modesto ID contends that had the Commission intended to use the methodology in D.03-04-030 for calculating the ongoing CTC for municipal departing load, it would have so stated. Modesto ID asserts that D.03-07-028 does not require the application of the calculation methodology set forth in D.03-04-030 and the benchmark established in D.02-11-022.

Modesto ID contends that any CTC applied to municipal departing load must be consistent with Assembly Bill (AB) 1890, wherein the Legislature specifically stated which costs could be recovered through the CTC. (See §§ 367, 368, 375 and 376.) Modesto ID contends that the provisions of § 367 must be read in context with AB 1890. According to Modesto ID, § 367(b) establishes the calculation mechanism for determining CTCs, i.e., net the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets. Section 367(a) establishes the ceiling which the CTCs determined by such calculation cannot exceed. Modesto ID contends that pursuant to § 368(b), the CTCs applied to municipal departing load customers must be the same as the CTC component that a bundled service customer pays.

According to the Modesto ID, PG&E applies § 367(a) in a vacuum without reference to the requirements of §§ 367(b) or 368. Modesto ID contends that PG&E has not provided any authority in support of its interpretation of § 367(a). Modesto ID points to a proposed resolution by the Energy Division which recognizes the need to treat all customers uniformly, and disagrees with imposing CTC rates that result in differing treatment of departing load customers.[8]

Even if PG&E's proposed CTC calculation methodology is permitted by § 367, Modesto ID contends that applying § 367(a) without regard to the offset

---

[8] The proposed resolution is the draft Energy Division Resolution E-3831, which was originally mailed on May 28, 2004. In a July 2, 2004 motion, PG&E moved to strike Modesto ID's reference to the resolution. Merced ID also referred to the draft resolution in footnote 8 of its reply brief. Modesto ID filed a response to the motion on July 12, 2004. The disposition of the motion is discussed later in this decision.

requirement in § 367(b) is discriminatory since § 368 prohibits discrimination among customers. Modesto ID asserts that the decisions in R.02-01-011 do not support PG&E's methodology of charging municipal departing load customers a different CTC than those charged to bundled customers.

Merced ID disputes PG&E's assertion that the Irrigation Districts have already agreed to the ongoing CTC calculation methodology that PG&E proposed in this proceeding. Merced ID contends that its brief in R.02-01-011, which PG&E cited in support of its position, only addressed what costs should be considered eligible for ongoing CTC cost recovery for purposes of municipal departing load cost recovery surcharges. Merced ID contends that its brief did not address the CTC calculation.

Merced ID also points out that the position of the Irrigation Districts is supported by the following statement in D.03-07-028 that references PG&E's Preliminary Statement BB: "We shall direct the IOUs continue [sic] to charge tail CTC to MDL pursuant to their approved tariffs." (Merced ID, Reply Brief, pp. 4-5; D.03-07-028, p. 46.) Merced ID points out that Preliminary Statement BB is PG&E's current tariff, and requires the same CTC to be charged to bundled, direct access, and municipal departing load customers.

Merced ID contends that because of PG&E's misinterpretation of past Commission decisions on the issue of the ongoing CTC calculation for municipal departing load customers, the Commission should calculate ongoing CTC as recommended by the Irrigation Districts and PG&E should be directed to implement the Commission's calculation.[9]

---

[9] Merced ID asserts that the purpose of § 367(a) is to identify only the costs that can be collected in ongoing CTC, while § 367(b) addresses the CTC calculation.

In the event the Commission does not adopt the Irrigation Districts' method of calculating the 2004 CTC revenue requirement, Modesto ID proposes that a benchmark of 6.874 cents per kWh, instead of the 5.18 cents benchmark, be adopted for calculating the 2004 ongoing CTC for municipal departing load customers. The benchmark was developed as a substitute for transactions with the Power Exchange (PX), which ceased operations during the energy crisis.

Modesto ID asserts that PG&E appears to use the 5.18 cents benchmark because the Commission agreed to use that proxy value for a combined cycle generating unit in SCE's 2004 ERRA proceeding. Modesto ID contends that no Commission decision has predetermined what market benchmark should be used to calculate PG&E's 2004 ongoing CTC revenue requirement for municipal departing load customers.

Modesto ID contends that the benchmark must reflect current market conditions. When the gas-fired combined cycle market proxy was adopted in D.02-11-022, the Commission voiced concern about using spot electric prices to determine the market proxy due to the unsettled state of the power markets and the volatility and unpredictability of such prices due to the ISO market redesign efforts and FERC oversight. These concerns no longer exist. Modesto ID also points out that the Commission recently adopted separate pricing proxies for combined cycle baseload and simple cycle peaking power plants in D.04-06-015 using a report of the CEC. Modesto ID contends that the CEC report can be used to develop a proxy that takes into consideration a balance of combined cycle, simple cycle and peaking power costs.

Modesto ID proposes that a realistic market benchmark be developed by blending a small amount of gas-fired peaking energy generation to compliment the gas-fired combined cycle generation. This can be accomplished by using the CEC cost information, and an average of adjusted low and high natural gas fuel costs. Modesto ID claims that its benchmark accounts for current gas cost data and the mix of resources used by utilities to serve their loads. Modesto ID asserts that such a benchmark more closely mirrors the current market price, and serves as a more accurate replacement for the PX price mechanism.

The use of Modesto ID's recommended benchmark produces an ongoing 2004 CTC for departing load customers of $0.00197 per kWh, which is slightly above PG&E's proposed $0.00184 per kWh average rate for bundled and direct access customers. (See Ex. 11, p. 16; Ex. 12.)

The Irrigation Districts also contend that certain QF contracts must be removed from PG&E's ongoing CTC calculation for 2004 because the calculation cannot include any costs incurred after the original expiration date of the QF contract, regardless of the process by which the contract extension was entered into. The first QF contracts that should be removed are the 16 contracts whose original contract terms were extended by Commission decisions. Modesto ID contends that § 367 only permits recovery of the costs associated with "power purchase contracts, including, but not limited to, restructuring, renegotiations or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995." (Modesto ID, Opening Brief, p. 11.)

Modesto ID points out that according to PG&E, the removal of these ineligible costs would reduce the forecasted QF costs by $36,000,000. This will result in a $7.12 million reduction to the total ongoing CTC revenue requirement, and a $36,000 reduction in the departing load CTC revenue requirement. Thus, the departing load CTC rate would decline to $0.00694 per kWh, and the average bundled and direct access rate would decline to $0.00167 per kWh.

The second set of QF contracts that should be removed from the CTC calculation are the SRAC amendments where the SRAC fixed price exceeded the fluctuating monthly SRAC price. PG&E's witness testified that 200 QF projects, which were included in the CTC calculation, entered into SRAC amendments. The SRAC amendments resulted in the SRAC price, that was previously adjusted on a monthly basis, to be replaced with a five-year fixed SRAC price of $5.37 per kWh. Modesto ID contends that §367 precludes "the recovery of costs associated with renegotiated contracts where the new contract price is higher than the contract price that was collected in Commission approved rates on December 20, 1995." (Modesto ID, Opening Brief, p. 12.) The affected QF contracts make up approximately 80% of PG&E's total QF cost forecast. The Irrigation Districts recommend that PG&E be required to recalculate the ongoing CTC excluding the ineligible QF costs mentioned above.

In response to the June 4, 2004 ruling soliciting comments on the effect of Exhibit 18 on prior years, Modesto ID contends that PG&E's tariff authorizing the collection of ongoing CTC expired no later than March 30, 2002. Modesto ID asserts that no replacement or retroactive reinstatement of this tariff has been authorized by the Commission. Thus, the ongoing CTC rate for 2003 is zero. Modesto ID agrees that so long as the Commission clarifies that there is no CTC liability for municipal departing load customers, that recalculation of the CTC for 2003 and earlier periods is not necessary.

Merced ID states that Exhibit 20 shows that six QF projects should not have received CTC treatment after the date of their original expiration prior to 2003, and there was no CTC rate for municipal departing load customers in 2003.

It appears though that PG&E may seek 2003 CTC cost recovery at some point in the future. Merced ID contends that if PG&E seeks to preclude adjustment of illegitimately collected QF-based CTC in past rates, then PG&E should not be allowed to assert that the Commission can still impose a CTC rate for 2003. Merced ID recommends that ongoing CTC should only apply prospectively beginning in 2004, and that past CTC should not be recalculated nor should ongoing CTC be imposed for 2003.

IV. Discussion

A. Introduction

There are essentially two issues before us regarding the CTC revenue requirement for 2004. The first issue is whether PG&E's calculation of the ongoing CTC revenue requirement for municipal departing load customers is correct. The second issue is whether PG&E's ongoing CTC revenue requirement for 2004 should be reduced due to the inclusion of some possibly ineligible QF contracts that were included in the CTC calculation. The outcome of these two issues may affect the interim decision reached in D.04-06-012.

D.03-07-030 directed that the CTC revenue requirement and rates beginning in 2004 be set in PG&E's ERRA application. PG&E's application, as modified by the April 23, 2004 Errata (Exhibit 18), requested that the Commission approve PG&E's 2004 ongoing CTC revenue requirement of $144.026 million, and its proposed rate design. PG&E proposes that the $144.026 million revenue requirement for ongoing CTC be allocated as follows: $15.247 million to direct access customers; $125.922 million to bundled customers; and $2.858 million to departing load customers.

PG&E's calculation of the ongoing CTC revenue requirement is described in Chapter 7 of PG&E's updated testimony submitted on February 17, 2004 (Exhibit 1), as modified by Exhibit 18. PG&E's proposed CTC rate design is described in Chapter 8 of Exhibit 1.

In D.04-06-012, we adopted on an interim basis, PG&E's ongoing CTC revenue requirement of $144.026 million, and PG&E's use of the 5.18 cents per kWh amount as the benchmark for calculating the ongoing CTC. We also adopted, on an interim basis, the CTC rates proposed by PG&E. (D.04-06-012, pp. 14-16.)

B. Calculation of the Ongoing CTC

The first issue that we address is whether PG&E's calculation of the ongoing CTC revenue requirement for municipal departing load customers is correct. PG&E takes the position that the Commission has already adopted a methodology for calculating the ongoing CTC revenue requirement for municipal departing load customers in D.03-07-028. The Irrigation Districts contend that the Commission has not adopted a methodology for calculating ongoing CTC for municipal departing load customers, and that the methodology that is adopted cannot be discriminatory.

The key to resolving the issue of whether the Commission adopted a methodology for calculating the ongoing CTC for municipal departing load customers is to review the proceedings which led to the issuance of D.02-11-022, D.03-04-030 and D.03-07-028.

D.02-11-022 and D.03-04-030 were issued as a result of the inquiry into the issue of the cost responsibility of direct access and departing load customers. (See March 29, 2002 ALJ Ruling in A.00-11-038 et al., and D.02-05-052 transferring the cost responsibility issues from A.00-11-038 et al. to R.02-01-011.) The March 29, 2002 ruling in A.00-11-038 at page 1 ordered "evidentiary hearings and sets a preliminary schedule relating to the issue of cost responsibility of Direct

Access customers." The ruling at page 6 also stated that the proceeding would address the issue of how departing load customers should be treated in terms of cost responsibility. (See D.03-04-030, p. 6.)

D.02-11-022 established the mechanisms to implement the surcharges applicable to direct access customers within the service territories of California's three major electric utilities. In that decision, we stated that the cost recovery surcharges for direct access customers should be "determined on a total portfolio basis, taking into account both DWR and utility-procured resources…." (D.02-11-022, pp. 3, 26, 165, OP 17.) The ongoing CTC was part of the direct access cost recovery surcharge. (D.02-11-022, p. 40.)

In an April 5, 2002 ruling in A.00-11-028 et al., interested parties were directed to address "any legal considerations that would be relevant with respect to assessing cost responsibility surcharges for Departing Load customers," and to address the "full range of costs in determining the appropriate cost responsibility for Departing Load customers." (April 5, 2002 Ruling in A.00-11-028, p. 2.) The ruling also stated "To the extent that there are different legal considerations that would apply to cost responsibility surcharges for Departing Load versus Direct Access customers, parties should identify and address such differences." (*Id.*) Following the filing of those briefs,[10] supplemental testimony on the departing load issues was submitted in September 2002. Six days of evidentiary hearings on the departing load issues were then held in October 2002.

---

[10] Many of the briefs that were filed in response to the April 5, 2002 ruling noted that without having specific cost recovery surcharge proposals before them to consider, that it would be difficult to fully address all the associated legal issues.

During the course of the hearings on the departing load issues, certain parties filed a motion in R.02-01-011 to adopt a settlement agreement regarding the cost responsibility of customer generation departing load customers. As a result, D.03-04-030 addressed the cost responsibility surcharges for customer generation departing load only.

The ongoing CTC was part of the cost recovery surcharge addressed in D.03-04-030. (See D.03-04-030, p. 4.) To calculate the ongoing CTC, D.03-04-030 defined the ongoing CTC using § 367(a)(1)-(6) and used the calculation set forth in footnote 72 at page 50 of D.03-04-030. The parties have referred to this as the statutory methodology.

D.03-04-030 further stated that: "This order does not address any other forms of DL [departing load] such as that served by municipally-owned utilities or irrigation districts." (D.03-04-030, p. 3.) In the footnote which followed this quotation, we stated: "Nothing in this order should be construed as prejudging or limiting what Commission positions or treatment may be adopted for any other form of DL not covered in this order." (D.03-04-030, p. 3, fn. 2.)

Since D.03-04-030 addressed the cost responsibility of customer generation departing load customers, the municipal departing load issues were bifurcated and addressed in D.03-07-028. (See D.03-07-028, p. 7; D.03-04-030, p. 8.)

Contrary to the Irrigation Districts' argument that the Commission has not yet adopted a CTC calculation methodology for municipal departing load customers, that issue was addressed in D.03-07-028. As we stated in the summary section of D.03-07-028:

> "Today's decision adopts policies and mechanisms to implement cost responsibility surcharges applicable to Municipal Departing Load (MDL) …. As defined in this

> order, MDL refers to departing load (DL) served by a 'publicly owned utility' as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts." (D.03-07-028, pp. 2, 7.)

In addressing the argument that the imposition of the cost responsibility surcharge on municipal departing load was unlawful, we stated:

> "We reject Municipal parties' arguments, however, that imposition of cost responsibility on departed IOU customers now served by publicly owned utilities constitutes regulation of the publicly owned utility. <u>The surcharges</u> that <u>we authorize herein</u> shall be part of the IOU tariffs, and as such, entail regulation of the IOUs. Although the surcharges will apply to customers that are presently being served by municipalities, <u>the surcharges will be calculated</u>, billed, and collected <u>as a function of IOU tariffs</u>. We defer to a separate order the specific means by which the billing and collection process will be implemented….
>
> "… <u>We thus authorize IOU tariff charges necessary to hold MDL customers responsible for costs necessary to prevent cost shifting</u> in accordance with AB 117, thereby ensuring that bundled customers' charges are just and reasonable consistent with Section 451. " (D.03-07-028, pp. 21-22, emphasis added.)

We also stated:

> "During the course of DL [departing load] hearings, certain parties entered into settlement discussions on issues relevant to DL served by customer generation. The disposition of Customer Generation DL was the subject of D.03-04-030. <u>This order addresses remaining DL CRS issues that relate to load served by publicly owned utilities</u> (i.e., municipal utilities and irrigation districts, as defined in Section 9604(d))." (D.03-07-028, p. 7, emphasis added.)

In OP 2 of D.03-07-028, we ordered the following:

> "<u>A Municipal Departing Load Cost Responsibility Surcharge</u> (MDL CRS) <u>mechanism is hereby adopted</u> applicable to designated customers that took bundled service on or after February 1, 2001 in the service territories of PG&E, SCE, and SDG&E and subsequently departed to be served by a 'publicly owned utility' as defined by Section 9604(d)." (D.03-07-028, p. 80, OP 2, emphasis added.)

In OP 3 of D.03-07-028, we authorized PG&E to file tariffs to implement the cost recovery surcharges for municipal departing load, including: "Tail Competitive Transition Charge (CTC) covering the components specified in Section 367, applicable to MDL customers in the IOU service territory as of December 20, 1995." (D.03-07-028, pp. 46, 81, OP 3.c.)

Among the parties who participated in the municipal departing load cost recovery surcharge phase of R.02-01-011 were CMUA, Merced ID, and Modesto ID. (D.03-07-028, p. 7.)

Based on the passages cited above, one can only conclude that the Commission did adopt a CTC mechanism for municipal departing load in D.03-07-028 using what parties have referred to as the statutory methodology. However, since the Irrigation Districts raised various arguments as to why they believe no CTC calculation methodology was adopted in D.03-07-028 for municipal departing load, we discuss those arguments below.

Merced ID contends that D.03-07-028 did not address "the proper method for calculating" the ongoing CTC beyond referring to § 367. (Merced ID, Opening Brief, p. 2.) Modesto ID states that "D.03-07-028 designated no specific rate design formula or benchmark criteria beyond reference to Section 367." (Modesto ID, Opening Brief, p. 6.) Modesto ID asserts that PG&E has interpreted the reference to § 367 as having the same effect as D.03-04-030 and used only § 367(a)(1)-(6) in its calculation. Merced ID asserts that none of the Commission decisions upon which PG&E relies require the ongoing CTC for municipal departing load to be calculated in the manner proposed by PG&E.

The Irrigation Districts contend that the reference to § 367 in OP 3(c) of D.03-07-028 must be read in conjunction with § 367(b), which they assert contains the calculation method. That is, the Irrigation Districts argue that the CTC is to "be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets." (Modesto ID, Opening Brief, p. 7; Merced ID, Opening Brief, p. 5; Pub. Util. Code § 367(b).) Since bundled and direct access customers were allowed to benefit from the offset of below-market utility owned generation-related costs, as set forth in D.02-11-022, the Irrigation Districts contend that the calculation of the ongoing CTC for municipal departing load must be calculated in the same manner pursuant to § 368(b). Merced ID also contends that PG&E's current tariff require ongoing CTC to be calculated as it is for bundled and direct access customers.

We disagree with the Irrigation Districts' interpretation.

In the summary of the parties' positions in the CTC section of D.03-07-028, we noted that:

> "For purposes of this proceeding, Merced defines tail CTC based upon Section 367, and thus limited to the following costs: (1) employee-related transition costs (through December 31, 2006); (2) existing power purchase contract obligations (through the duration of the contract); (3) nuclear incremental cost incentive plans for San Onofre (through December 31, 2003); and (4) fixed transition amounts, as applicable. Merced opposes any effort to expand tail CTCs beyond these statutorily authorized costs." (D.03-07-028, p. 44.)

In summarizing PG&E's position, we stated:

> "PG&E notes that under Section 840(f), IOUs may include uneconomic costs of power purchase contracts within the definition of transition costs. Section 367(a) directs the Commission to identify and determine categories of transition costs, including those identified in Section 840(f), for collection on a nonbypassable basis from all customers by December 31, 2001. Section 367(a) further provides that collection of certain transition costs – or 'tail CTC' – could extend beyond December 31, 2001. Included among those costs eligible for 'tail CTC' treatment are power purchase obligations." (D.03-07-028, p. 45, footnote omitted.)

In the discussion portion of the CTC section of D.03-07-028, we stated: "We shall direct the IOUs [sic] continue to charge tail CTC to MDL pursuant to their approved tariffs." (D.03-07-028, p. 46.) In Finding of Fact 25, we stated: "A provision for ongoing or 'tail' CTC covering the cost categories defined in Section 367 is a necessary component of the MDL CRS in order to achieve bundled customer indifference." (D.03-07-028, p. 78.)

When the CTC section is read together with Finding of Fact 25 and OP 3.c. of D.03-07-028, we can only conclude that a methodology for calculating the ongoing CTC was adopted using the so-called "statutory" method.[11]

This conclusion is further supported by the subsequent advice letter tariff filing that PG&E made in response to D.03-07-028. Advice Letter 2433-E was filed on October 29, 2003.[12] That advice letter stated in pertinent part:

> "Pursuant to D.03-07-028, MDL customers will pay statutory CTC charges, which are the same CTC charges that apply to Customer Generation Departing Load customers. (See D.03-07-028, pp. 39-44, adopting the P.U. Code Section 367 statutory definition of CTCs for MDL customers). In contrast, pursuant to D.02-11-022, direct access and bundled customers are currently subject to CTC charges based on a 'total portfolio' methodology, as opposed to the P.U. Code

---

[11] Although PG&E and the Irrigation Districts argue that the Commission adopted two different methodologies for calculating the ongoing CTC, i.e., the statutory method and the total portfolio method, under both methods, the calculation of the ongoing CTC is based on the requirements of § 367(a)(1)-(6).

[12] PG&E subsequently filed supplemental Advice Letter 2433-E-A on November 4, 2003, and supplemental Advice Letter 2433-E-B on February 18, 2004. These two supplemental advice letters propose to make changes to Advice Letter 2433-E which are not relevant to this discussion.

> Section 367 statutory definition." (PG&E Advice Letter 2433-E, p. 3.)

Modesto ID's protest to Advice Letter 2433-E, which was submitted on November 18, 2003, did not raise the issue that municipal departing load customers would have to pay the "statutory CTC charges," as opposed to paying "CTC charges based on a 'total portfolio' methodology." (See Ex. 13, p. 2.)

The next argument to address is Merced ID's contention that the calculation of the ongoing CTC is contrary to Preliminary Statement BB of PG&E's tariffs. Specifically, Merced ID contends that the current Preliminary Statement BB requires the same CTC to be charged to bundled, direct access, and municipal departing load customers.

PG&E states in Exhibit 4 at page 1-2 that it "agrees that its proposed implementation of the Ongoing CTC is inconsistent with the quoted language from Preliminary Statement BB." However, PG&E points out that Preliminary Statement BB was filed five years ago to comply with the Commission's then-current decisions on CTC responsibility, and has since been overtaken by the recent decisions regarding the calculation of the CTC. In addition, PG&E has filed advice letters proposing new tariffs to implement those decisions and to supersede the existing Preliminary Statement BB.

The argument of Merced ID that PG&E's ongoing CTC calculation is contrary to the current Preliminary Statement BB ignores the decisions which came after Preliminary Statement BB, and the advice letters that have been filed to change the Preliminary Statement. As PG&E correctly points out, Preliminary Statement BB was filed approximately five years ago to comply with the then current decisions on CTC responsibility. Since that time, the decisions on customer generation departing load (D.03-04-030) and municipal departing load

(D.03-07-028) have overtaken Preliminary Statement BB. As a result of those two decisions, PG&E filed Advice Letters 2375-E and 2433-E on April 17, 2003 and October 29, 2003, respectively, to propose new tariffs to implement those decisions and to supersede portions of Preliminary Statement BB.[13] Thus, PG&E's current Preliminary Statement BB contains tariff language that conforms to past Commission decisions, and does not reflect the recent mandates contained in D.03-04-030 and D.03-07-028. In light of these developments, we cannot agree with Merced ID's contention that the existing Preliminary Statement BB should prevail. To do so would ignore D.03-04-030 and D.03-07-028.

Based on the foregoing analyses, the Irrigation Districts' argument that the "Commission has not yet established a CTC calculation methodology for Municipal Departing Load"[14] is not supported by the evidence. The statutory calculation methodology for ongoing CTC was raised and addressed in the proceeding leading to the issuance of D.03-04-030 and D.03-07-028.

We also note that the statutory calculation methodology adopted in D.03-07-028 for ongoing CTC was not raised as an issue in the applications for rehearing of D.03-07-028 that were filed by CMUA and Modesto ID. (See D.03-08-076, pp. 1-3.) Similarly, no applications for rehearing of D.03-04-030 challenged the calculation of the ongoing CTC for customer generation departing load.[15] Since the statutory calculation methodology was not raised on rehearing

---

13 The Commission has not yet acted on Advice Letters 2375-E and 2433-E.

14 See Modesto ID's Opening Brief, June 14, 2004, p. 6.

15 The Irrigation Districts' argument that § 368(b) requires that the CTC rate for municipal departing load be the same as the rate for direct access and bundled

Footnote continued on next page

for either D.03-04-030 or D.03-07-028, both decisions are final and are conclusive in all collateral actions or proceedings. (See Pub. Util. Code §§ 1709, 1735.) It is too late for the Irrigation Districts to raise in this proceeding the legal challenge that D.03-04-030 and D.03-07-028 are contrary to § 368(b).[16] Accordingly, PG&E's calculation of the ongoing CTC using the statutory method shall remain unchanged.

C. Benchmark Price Issue

In the event the Commission does not agree with the Irrigation Districts' argument that the ongoing CTC calculation for municipal departing load should be the same as for bundled and direct access customers, then Modesto ID recommends that the Commission adopt a market benchmark of 6.874 cents per kWh for the ongoing CTC calculation instead of the 5.18 cents benchmark that PG&E uses.

According to the Modesto ID, when the 6.874 cents per kWh benchmark is used in PG&E's model, the resulting 2004 ongoing CTC rate for departing load customers is $0.00197 per kWh. The use of Modesto ID's proposed market benchmark produces an ongoing CTC revenue requirement that is lower than PG&E's proposed CTC. The rate resulting from Modesto ID's

---

customers, is an argument that should also apply to the CTC rate that is charged to customer generation departing load. However, no one raised this issue with respect to the calculation of the ongoing CTC in D.03-04-030.

[16] We also note that the Irrigation Districts' argument that the cost responsibility surcharges for municipal departing load customers should be the same as the surcharges for direct access and customers was not raised in the April 22, 2002 briefs that Merced ID or Modesto ID filed in response to the April 5, 2002 ruling in A.00-11-038 et al., which invited legal arguments about the cost responsibility of departing load customers.

benchmark is slightly above PG&E's proposed $0.00184 per kWh average 2004 ongoing CTC rate for bundled and direct access customers.

Our approach for resolving the issue of whether a different market benchmark should be used to calculate the ongoing CTC is to examine how the benchmark was established, and the parties' criticisms of each other's benchmark.

The market benchmark for calculating the ongoing CTC was first established in D.02-11-022. A benchmark was needed because the CTC "was defined in D.97-06-060 and D.97-11-074 as being the difference between the utilities' actual cost of a particular asset or contract and the short-term Power Exchange (PX) price." (D.02-11-022, p. 107.) Since the PX was no longer operating, "a new market price benchmark must be established for use in calculating CTC." (*Id.*) We determined in D.02-11-022 that "the use of a gas-fired combined cycle unit offers the most appropriate proxy measure." We also stated that "spot price proxies are too unstable and unreliable to form the basis for a market proxy." (*Id.*) As a result, the cost of a gas-fired combined cycle generating unit was established as the market proxy for the 2003 direct access cost recovery surcharge calculations. The adopted benchmark of 4.3 cents per kWh was based on a 15-year levelized cost calculation, which referenced a CEC study. (*Id.*, at pp. 108, 160, COL 35, 165, OP 16.) We also stated in D.02-11-022 that "the market proxy value should be regularly updated with each annual updating of the DA CRS component for URG to reflect the most current and reliable data." (*Id.*, at pp. 108-109.)

In D.03-07-030, the decision which addressed a cap on the direct access cost responsibility surcharge, we stated that "For the year 2004 and subsequent years, the 4.3 cents benchmark will be subject to revision to reflect more updated data." (D.03-07-030, p. 14.)

In this proceeding, PG&E proposes that a market benchmark of 5.18 cents per kWh be used. According to PG&E, this "reflects the CEC's most recent update of the levelized costs for a gas-fired combined cycle generator." (Ex. 4, p. 2-2.)[17] PG&E also points out that this benchmark of 5.18 cents was used in SCE's 2004 ERRA proceeding, A.03-10-022. (See D.04-04-066, pp. 5-6.)[18]

The benchmark of 5.18 cents was based on the CEC's October 2003 draft report entitled Electricity and Natural Gas Assessment Report, which estimated the cost of a gas-fired combined cycle baseload unit. (D.04-04-066, p. 5, fn. 5; 1 R.T. 72, 76.) In adopting the 5.18 cents benchmark, we stated in D.04-04-066 that the "use of information from the California Energy Commission is a reasonable basis for making this revision." (*Id.,* at p. 6.)

Since the CTC definition uses the PX price, Modesto ID asserts that in the absence of a PX price, "a new market price benchmark must be established in order to calculate CTC." (Modesto ID, Opening Brief, p. 8.) Modesto ID proposes that a benchmark of 6.874 cents per kWh, instead of the 5.18 cents, be used to calculate the 2004 ongoing CTC rate for PG&E's municipal departing

---

[17] The levelized cost of 5.18 cents per kWh is based on a 20-year forecast of gas prices. (2 R.T. 165; Ex. 4, p. 2-3.)

[18] There is a typographical error in D.04-04-066 about the amount of the benchmark that was adopted. At page 5 and Finding of Fact 4 of that decision, the benchmark is referred to as 5.18 cents per kWh, while at page 6, the benchmark is referred to as 5.13 cents per kWh. The CEC's December 2003 Electricity and Natural Gas Assessment Report in Table B-1 at page B-3 lists the cost of a combined cycle baseload gas fired plant at 5.18 cents per kWh.

load customers. Modesto ID's witness testified that its 6.874 cents benchmark was "developed by blending a small amount of natural gas fired peaking energy generation to complement the natural gas fired combined cycle power energy using CEC cost information and the average of the low and high natural gas fuel cost adjusted levelized energy costs…." (Ex. 11, pp. 15-16.)

The key in deciding which benchmark to adopt is the language that the benchmark "will be subject to revision to reflect more updated data." (D.03-07-030, p. 14.)

We found in D.02-11-022 that the use of a gas-fired combined cycle generating unit offered the most appropriate market proxy. (D.02-11-022, p. 107.) In D.02-11-022, the Commission found that the use of a 15-year levelized cost was appropriate. We used the 4.3 cents benchmark for calculating the 2003 direct access cost recovery surcharge for all three electric gas utilities, and emphasized that the market proxy should be regularly updated with each annual updating of the direct access cost recovery surcharge component for URG to reflect the most current and reliable data. (D.02-11-022, p. 109.) Then in D.03-07-030, the decision which continued the cap on the direct access cost responsibility surcharge, we stated:

> "Since it was the intent in D.02-11-022 to adopt the 4.3 cents/kWh as an initial benchmark for use in determining above-market resource costs, parties should apply this value for computing CTC for the years 2001 through 2003. For the year 2004 and subsequent years, the 4.3 cents benchmark will be subject to revision to reflect more updated data." (D.03-07-030, pp. 13-14.)

Based on our prior statements in D.02-11-022 and D.03-07-030, PG&E's benchmark of 5.18 cents per kWh should be used in the calculation of the ongoing CTC for municipal departing load. PG&E's benchmark uses a 20-year levelized cost of a gas-fired combined cycle generating unit. This levelized cost is similar to the 15-year levelized cost that made up the adopted 4.3 cents benchmark in D.02-11-022. In addition, the 5.18 cents benchmark is for a gas-fired combined cycle unit, which in D.02-11-022 was found to be the "most appropriate proxy measure." (D.02-11-022, pp. 107, 151, FOF 20.) PG&E's benchmark meets the characteristics of the benchmark that was previously adopted in D.02-11-022.

PG&E's benchmark continues to use the cost of a combined cycle generating unit by using updated data from the CEC. Modesto ID's benchmark, on the other hand, uses a small amount of gas fired peaking generation together with combined cycle generation, and the average of the low and high natural gas fuel cost using PG&E's 2004 fuel forecast of 5.602 as the base. We agree with PG&E, that instead of updating the costs of the adopted market proxy, Modesto ID uses a different set of data and assumptions in its proposed benchmark.

Another reason for adopting PG&E's benchmark of 5.18 cents is that it has been adopted for use in SCE's ERRA proceeding in D.04-04-066. The original benchmark of 4.3 cents was adopted for the calculation of the cost recovery surcharge for all three electric utilities in California. Modesto ID seeks to apply its proposed benchmark of 6.874 cents per kWh to PG&E only. Based on how the market benchmark was developed, the same benchmark should apply to all three utilities.

Modesto ID also proposes to use its 6.874 cents benchmark to calculate the ongoing CTC for municipal departing load only. Modesto ID does not intend to use the 6.874 cents benchmark to calculate the CTC rates for direct access customers, but instead would use the 5.18 cents benchmark.

Based on the reasons described above, we adopt the 5.18 cents per kWh benchmark that PG&E has proposed for use in calculating the ongoing CTC.

D. The Effect of PG&E's Errata

1. Background

During the course of the hearings, PG&E witness Pappas testified that some QF contracts might need to be removed from the ongoing CTC revenue requirement due to ineligibility. PG&E's Errata, Exhibit 18, removed five QF contracts from the CTC revenue requirement. The Errata and the data responses regarding portions of the Errata were admitted into evidence. In the June 4, 2004 ruling, the assigned ALJ asked the parties to comment in their opening and reply briefs on the effect of the Errata on the prior ERRA and CTC calculations. Specifically, the parties were asked to address the following:

> (1) Does the inclusion of the five qualifying facility contracts in Exhibit 18 affect the calculations of the ERRA and CTC in prior years, and if so, what is the numerical effect on those calculations?
>
> (2) Should the Commission adjust the ERRA and CTC in the prior years to account for the possible overcollection of the CTC and undercollection of the ERRA?
>
> (3) Are there any settlements or Commission decisions which may prevent the Commission from adjusting the ERRA and CTC for those prior years?
>
> (4) Are further evidentiary hearings needed to resolve this adjustment issue?

In response to Question 4, PG&E and the Irrigation Districts stated that no additional hearings were needed on the Errata.

With respect to Questions 1 and 3, PG&E notes that the ERRA has only been in effect since 2003. For 2003, including the cost of the five QF contracts would have increased the 2003 ERRA revenue requirement and reduced the 2003 ongoing CTC revenue requirement. PG&E points out, however, that since direct access and municipal departing load customers were subject to a cost responsibility surcharge capped at 2.7 cents per kWh, that the 2003 customer rates of bundled, direct access, and departing load were not affected. Since the Commission did not establish an ongoing CTC revenue requirement for 2003 for direct access and departing load customers, PG&E contends that such a determination should be made in R.02-01-011 rather than in this proceeding.

For the regular CTC, as opposed to ongoing CTC, PG&E asserts that the five QF contracts cannot affect the CTC rates for years prior to 2003 because PG&E's transition cost balances have already been resolved in PG&E's Annual Transition Cost Proceedings, and PG&E's bankruptcy settlement decisions in D.03-12-035 and D.04-02-062.

In response to Question 2 of the June 4, 2004 ruling, PG&E contends that the Commission should not adjust the ERRA or the CTC in prior years. PG&E asserts that because of the modified bankruptcy settlement adopted in D.03-12-035, the "revenues collected through and including December 31, 2003 were to be finalized and either refunded or collected from customers in rates." (PG&E, Opening Brief, p. 11.) The rates to implement the modified bankruptcy settlement were approved by the Commission in D.04-02-062.

2. Sixteen QF Contracts

Merced ID contends that PG&E must remove an additional 16 QF contracts from the CTC revenue requirement.[19] Although the costs of these 16 QF contracts may be recovered elsewhere in PG&E's rates, the Irrigation Districts contend that these QF contracts cannot be recovered through the CTC because § 367(a)(2) limits the recovery of CTC for QFs to their original contract expiration dates. Merced ID asserts that these 16 QF contracts were extended beyond their original expiration dates and are therefore ineligible for CTC treatment. As a result, the Irrigation Districts assert that the total ongoing CTC revenue requirement should be reduced by $7.12 million, and the departing load revenue requirement should be reduced by $36,000. (See Ex. 20, pp. 2-4.)

PG&E asserts that the 16 QF contract extensions that the Irrigation Districts seek to remove were the result of Commission directives in D.02-08-071 and D.03-12-062. PG&E contends that there is nothing in § 367(a)(2) that bars the Commission from granting ongoing CTC treatment to eligible QF contracts that the Commission required the utilities to extend. PG&E asserts that it did not buy-down, buy-out, or renegotiate there contracts. PG&E argues that it would be unreasonable for the Commission to order the utilities to extend their QF contracts, and then deny them the opportunity to recover these costs through the CTC.

---

[19] Modesto ID's opening brief contends that at least six QF contracts that expired prior to 2004 must be removed from the 2004 ongoing CTC calculation, and an additional eight contracts expiring in 2004 must be prorated.

Merced ID asserts that PG&E's reliance on D.02-08-064[20] and D.03-12-062 to justify inclusion of the 16 QF contracts is misplaced. Merced ID contends that those two decisions only address whether the utilities should be required to extend certain QF contracts, and did not even discuss CTC cost recovery after the expiration date of the original contract.

The central issue in deciding whether the 16 QF contracts should be removed from the CTC revenue requirement is whether § 367(a)(2) limits PG&E's ability to recover these costs. Section 367(a)(2) provides that transition costs are to be recovered by December 31, 2001 except that:

> "Power purchase contract obligations shall continue for the duration of the contract. Costs associated with any buy-out, buy-down, or renegotiation of the contracts shall continue to be collected for the duration of any agreement governing the buy-out, buy-down, or renegotiated contract; provided, however, no power purchase contract shall be extended as a result of the buy-out, buy-down, or renegotiation." (Pub. Util. Code § 367(a)(2).)

In reviewing D.02-08-071 and D.03-12-062, it is clear that the Commission ordered the electric utilities to extend the QF contracts. In OP 7 of D.02-08-071, we stated:

> "IOUs are required to offer SO1 [Standard Offer 1] contracts, whose term ends at the time that the IOU fully implements its long-term procurement plan approved by

[20] Although Merced ID's Opening Brief at page 8 cites to D.02-08-064, it appears Merced ID was referring to D.02-08-071. (See Merced ID Opening Brief, p. 8, fn. 26; Ex. 1, p. 5-2.)

the Commission, or on December 31, 2003, whichever occurs first, to any QF meeting the following conditions:

- The QF must have been in operation and under contract to provide power with an IOU at any point between January 1, 1998 and the effective date of this decision

- The QF contract must be set to expire before January 1, 2004 or have already expired, or have been terminated." (D.02-08-071, p. 43, OP 7.)

In OP 14 of D.03-12-062, we ordered that "QFs in operation and under contract to provide power to an IOU at any point between January 1, 1998 and the present date, whose contracts are set to expire before January 1, 2005, shall be afforded interim treatment, consistent with that provided in D.02-08-071."

PG&E and the QFs did not seek to alter the terms of the contracts by themselves. Instead, the Commission ordered PG&E and the other IOUs to offer SO1 contracts to QFs which met the stated criteria. Since the Commission ordered PG&E to do this, we cannot agree with the Irrigation Districts that the resulting extension of the 16 QF contracts was the result of a "buy-out, buy-down, or renegotiation." That is, the circumstances by which the terms of the QF contracts were changed are not covered by § 367(a)(2). Accordingly, we conclude that § 367(a)(2) does not bar PG&E from including the 16 QF contracts as part of the CTC revenue requirement.

3. Short Run Avoided Cost Contracts

Modesto ID contends that the 200 QF contracts that were renegotiated as a result D.01-06-015, which allowed the SRAC price to be replaced with a five-year fixed SRAC price of $5.37 per kWh, must be removed from the CTC calculation as well. Modesto ID asserts that § 367 only permits the recovery of costs collected in Commission-approved rates on December 20, 1995.

PG&E asserts that there is nothing in § 367 generally, or in § 367(a)(2), that prohibits the Commission from allowing recovery of the costs of the QF contracts that have renegotiated SRAC amendments. PG&E points out that § 367(a)(2) specifically provides that "Costs associated with any … renegotiation of the contracts shall continue to be collected for the duration of any agreement governing the … renegotiated contract." (PG&E, Reply Brief, p. 12; see Pub. Util. Code § 367(a)(2).) PG&E also notes that it was directed by the Commission in OPs 2 and 5 of D.01-06-015 to enter into the SRAC amendments with eligible QFs, and that 200 SRAC amendments were the result of the Commission's order.

In D.01-06-015, we stated that "QFs that are interested in such a non-standard pricing arrangement should be afforded the opportunity to modify their existing contracts." (D.01-06-015, p. 4.) We also stated in OP 3 of D.01-06-015 that the utilities "shall be authorized to recover all reasonable payments made under the amendments subject to their prudent administration of the amendments." Unlike the situation with the 16 QF contracts discussed above, the 200 QF contracts that were amended were voluntary.

Modesto ID does not dispute that the 200 QF contracts were being collected in "commission-approved rates on December 20, 1995." (Pub. Util. Code § 367.) Modesto ID apparently argues that the voluntary renegotiation of the QF contracts following D.01-06-015 should make these 200 QF contracts ineligible for CTC cost recovery. We disagree. Since these QF contracts were in existence on December 20, 1995, they qualify for recovery under § 367.[21] Although the amendment of the 200 QF contracts resulted in a different energy price being paid to the QFs, there are no provisions in § 367 that would make the amended contracts ineligible for CTC cost recovery. As PG&E points out, § 367(a)(2) specifically provides that the "Costs associated with any … renegotiation of the contracts shall continue to be collected for the duration of any agreement governing the … renegotiated contract…." (PG&E, Reply Brief, p. 12; Pub. Util. Code § 367(a)(2).) The 200 QF contracts that were amended as a result of D.01-06-015 were properly included as part of the CTC.

4. Recalculation

Regarding the issue of whether the ERRA and the CTC should be recalculated for 2003, and before 2003 for the CTC, because of PG&E's Errata, it is our belief that the ERRA and CTC revenue requirements should not be recalculated for the reasons set forth in PG&E's Opening Brief.

On the issue of whether PG&E should be allowed to recover ongoing CTC in 2003, we will defer that issue to R.02-01-011. It is in that proceeding where PG&E's 2003 ongoing CTC is to be decided. (See D.03-07-030, p. 110, OP 17; D.03-10-059, p. 4.)

E. Rate Design

In its rate design of the ongoing CTC for municipal departing load, PG&E used a single-rate method. According to PG&E, the single-rate method

---

[21] In D.97-11-074, while summarizing the provisions of § 367, we stated that the "Costs associated with power purchase contracts, including those QF contracts in place as of December 20, 1995, may be collected for the duration of the contract." (76 CPUC2d 627, 649.)

was used because D.03-07-028 was silent as to the appropriate rate design for municipal departing load customers. The single rate design method was used for customer generation departing load in footnote 72 of D.03-04-030.

During the evidentiary hearing, PG&E stated that if the Commission directed it to do so, it would be willing to change the rate design method to the top 100-hour method that was used in D.02-11-022. The top 100-hour method was used by PG&E to calculate the ongoing CTC rate for direct access customers as required by OP 29 of D.02-11-022.

The Irrigation Districts assert that the rate design that PG&E uses to derive the ongoing CTC rate for municipal departing load customers must be the same as for direct access customers. This argument of the Irrigation Districts is tied to their argument on how the ongoing CTC revenue requirement was derived. The arguments concerning the proper methodology have been addressed in this decision. Since we have concluded that the methodology that PG&E used to calculate the ongoing CTC was correct, the single rate method for designing the ongoing CTC rate for municipal departing load shall be used. Application of the single rate method results in an ongoing 2004 CTC rate for departing load customers of $0.00703 per kWh. (Ex. 18, p. 4.)

F. Conclusion

Based on our foregoing analyses and discussion, there is no need to adjust the CTC calculation as recommended by the Irrigation Districts. The PG&E 2004 ERRA revenue requirement of $2.189 billion is adopted, and the 2004 CTC revenue requirement amount of $144.026 million is adopted. The rates set forth in Table 8.1 of Exhibit 18 are adopted as the CTC rates for direct access and bundled service customers, and the rate of $0.00703 per kWh is adopted as the rate for departing load customers.

This proceeding remains open to address the 2003 record review period.

V. PG&E Motion to Strike

PG&E filed a motion on July 2, 2004 to strike a portion of Modesto ID's June 24, 2004 reply brief. PG&E requests that the statements at page 4 of the reply brief, pertaining to the draft Energy Division Resolution E-3831, be stricken because the draft resolution has not been finalized and is currently the subject of debate before the Commission. The June 24, 2004 reply brief of Merced ID also referred to the draft resolution in footnote 8 at page 5.

Modesto ID filed a response on July 12, 2004 in opposition to PG&E's motion. Modesto ID contends that its reply brief clearly recognized that the draft resolution was only being proposed and does not contend that the draft resolution is binding. Modesto ID believes that the reference to the draft resolution "is instructive on the issue of uniformity of tail CTC rates among customer classes." (Modesto ID, July 12, 2004 Response, p. 1.)

The reference to the draft resolution is merely an argument that Modesto ID made in support of its position, and has not been accorded any additional weight. PG&E's motion to strike the reference to the draft resolution in Modesto ID's reply brief is denied.

VI. Comments on Proposed Decision

The proposed decision of the ALJ was mailed to the parties on November 15, 2004. Comments on the proposed decision were filed by the Alliance for Retail Energy Markets, Merced ID, and Modesto ID. Reply comments were filed by Merced ID, Modesto ID, and PG&E.

The comments and reply comments have been considered, and the reference in the proposed decision to the "negative" CTC has been removed from this decision.

VII. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner, and John S. Wong is the assigned ALJ in this proceeding.

Findings of Fact

1. D.04-06-012 adopted on an interim basis a 2004 ERRA revenue requirement of $2.189 billion, a 2004 ongoing CTC revenue requirement of $144.026 million, PG&E's use of the 5.18 cents per kWh benchmark, and the CTC rates proposed by PG&E.
2. Evidentiary hearings on the CTC revenue requirement were held on April 5 and April 7, 2004.
3. PG&E's Errata, and seven PG&E data responses related to the Errata, were admitted into evidence without further hearings.
4. The June 4, 2004 ALJ ruling solicited comment on whether the Errata could affect the prior calculations of the ERRA and CTC revenue requirements.
5. D.02-11-022 and D.03-04-030 were issued as a result of the inquiry into the issue of the cost responsibility of direct access and departing load customers.
6. The April 5, 2002 ruling in A.00-11-028 et al. directed interested parties to address any relevant legal considerations with respect to assessing cost responsibility surcharges for departing load customers, and to identify and address any legal considerations with respect to cost responsibility surcharges for departing load versus direct access customers.
7. D.02-11-022 determined that the cost recovery surcharges for direct access customers should be done on a total portfolio basis.

8. Six days of evidentiary hearings on the departing load issues were held in October 2002.

9. A motion was filed in R.02-01-011 to adopt a settlement agreement regarding the cost responsibility of customer generation departing load customers.

10. As a result of the motion to adopt the settlement agreement, D.03-04-030 only addressed the cost responsibility surcharges for customer generation departing load.

11. D.03-04-030 did not address departing load that is served by municipal utilities or irrigation districts.

12. Since D.03-04-030 addressed the cost responsibility of customer generation departing load customers, the municipal departing load issues were bifurcated and addressed in D.03-07-028.

13. D.03-07-028 summarized the positions of Merced ID and PG&E regarding the costs which make up the ongoing CTC.

14. Advice Letter 2433-E stated in part that municipal departing load "customers will pay statutory CTC charges, which are the same CTC charges that apply to Customer Generation Departing Load customers."

15. Modesto ID's protest to Advice Letter 2433-E did not raise the issue that municipal departing load customers would have to pay the statutory CTC charges as customer generation departing load, as opposed to paying CTC charges based on a total portfolio methodology.

16. None of the applications for rehearing of D.03-04-030 and D.03-07-028 raised a challenge to the adoption of the statutory methodology in those two decisions.

17. D.02-11-022 determined that the use of a gas-fired combined cycle generating unit was the most appropriate market proxy for the short-term PX price.

18. D.02-11-022 adopted a market benchmark of 4.3 cents per kWh, referencing a CEC study.

19. D.02-11-022 stated that the market proxy should be regularly updated to reflect the most current and reliable data, and D.03-07-030 stated that the benchmark would be subject to revision to reflect more updated data.

20. PG&E's proposed benchmark of 5.18 cents was based on a CEC report which estimated the cost of a gas-fired combined cycle baseload unit.

21. PG&E's benchmark of 5.18 cents uses a 20-year levelized cost of a gas-fired combined cycle generating unit, which is similar to the 15-year levelized cost that made up the 4.3 cents benchmark adopted in D.02-11-022.

22. The market benchmark proposed by Modesto ID uses a different set of data and assumptions.

23. The benchmark of 5.18 cents has been adopted by the Commission in D.04-04-066 for use in SCE's ERRA proceeding.

24. In D.02-08-071 and D.03-12-062, the Commission ordered the electric utilities to extend the QF contracts which met the stated criteria.

25. The 200 QF contracts, that were later renegotiated pursuant to D.01-06-015, were being collected in rates on December 20, 1995.

26. The Irrigation Districts' argument concerning the rate design of the ongoing CTC is tied to their argument concerning the proper methodology for calculating the CTC revenue requirement.

27. PG&E filed a motion on July 2, 2004 to strike a portion of Modesto ID's June 24, 2004 reply brief.

Conclusions of Law

1. To calculate the ongoing CTC, D.03-04-030 defined the ongoing CTC using § 367(a)(1)-(6) and used the calculation set forth in footnote 72 at page 50 of D.03-04-030.

2. Based on a review of various passages in D.03-07-028, and when the CTC section of D.03-07-028 is read together with Finding of Fact 25 and Ordering Paragraph 3.c. of D.03-07-028, a methodology for calculating ongoing CTC was adopted in D.03-07-028 using the statutory method.

3. PG&E's Preliminary Statement BB, which was filed five years ago, has since been overtaken by recent decisions regarding the calculation of the CTC and the filing of advice letters proposing new tariffs to implement those decisions and to supercede the existing Preliminary Statement BB.

4. The Irrigation Districts' argument that the Commission has not yet established a CTC calculation methodology for municipal departing load is not supported by the evidence.

5. D.03-04-030 and D.03-07-028 are final and are conclusive in all collateral actions or proceedings.

6. It is too late to raise the legal challenge that D.03-04-030 and D.03-07-028 are contrary to § 368(b).

7. Based on prior statements in D.02-11-022 and D.03-07-030, PG&E's benchmark of 5.18 cents per kWh should be used in the calculation of the ongoing CTC for municipal departing load.

8. PG&E's benchmark meets the characteristics of the market benchmark that was previously adopted in D.02-11-022.

9. Based on how the market benchmark was developed, the same market benchmark should apply to all three electric utilities in California.

10. PG&E's market benchmark of 5.18 cents per kWh should be adopted for calculating the ongoing CTC.

11. Section 367(a)(2) does not bar PG&E from including the 16 QF contracts as part of the CTC revenue requirement.

12. Since the 200 QF contracts were in existence on December 20, 1995, and although the amendment of the 200 QF contracts resulted in a different energy price being paid to the QFs, there are no provisions in § 367 that make the amended contracts ineligible for CTC cost recovery.

13. The revenue requirements for the ERRA and CTC for 2003, and before 2003 for the CTC, should not be recalculated for the reasons set forth in PG&E's opening brief.

14. The issue of whether PG&E should be allowed to recover ongoing CTC in 2003 should be deferred to R.02-01-011.

15. The single rate method for designing the ongoing CTC rate for municipal departing load shall be used.

16. The Commission should adopt for PG&E a 2004 ERRA revenue requirement of $2.189 billion, the 2004 CTC revenue requirement of $144.026 million, the rates set forth in Table 8.1 of Exhibit 18 as the CTC rates for direct access and bundled service customers, and the rate of $0.00703 per kWh for departing load customers.

17. This proceeding remains open to address the 2003 record review period.

18. PG&E's July 2, 2004 motion to strike the reference to the draft resolution in Modesto ID's reply brief is denied.

O R D E R

IT IS ORDERED that:

1. The July 2, 2004 motion of Pacific Gas and Electric Company (PG&E) to strike a portion of Modesto Irrigation District's June 24, 2004 reply brief is denied.

2. The 2004 Energy Resource Recovery Account (ERRA) revenue requirement of $2.189 billion for PG&E is adopted.

3. The 2004 Competition Transition Charge (CTC) revenue requirement of $144.026 million for PG&E is adopted, and the market benchmark of 5.18 cents per kilowatt hour shall be used to calculate the ongoing CTC for municipal departing load.

4. The rates shown in Table 8-1 of Exhibit 18, a copy of which is summarized at page 15 of D.04-06-012, is adopted as PG&E's 2004 CTC rates for direct access and bundled service customers.

5. The rate of $0.00703 per kilowatt hour is adopted as PG&E's 2004 CTC rate for departing load customers.

6. This proceeding shall remain open to address the 2003 record review period.

This order is effective today.

Dated January 13, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners